EQUATORIAL ENERGY INC.

EQUATORIAL
the 2001 annual report

2001

Equatorial Energy Inc. is a Calgary-based independent corporation engaged in the acquisition, exploration, and development of petroleum and natural gas interests in Western Canada and Indonesia.

CONTENTS

2 Highlights
5 President's Message to Shareholders
10 Operations Review (Canada)
14 Operations Review (Indonesia)
20 Management's Discussion & Analysis
26 Management's & Auditors' Reports
30 Notes to Financial Statements
40 Corporate & Annual Meeting Information
IBC Employee Listing & Glossary

at a GLANCE

Equatorial enters 2002 with a stronger asset base and better prospects than ever in the Company's brief history. In Canada, we successfully sold high operating cost, geographically scattered properties and will continue to narrow our focus in 2002. Our Canadian operations achieved exceptional proved finding and development costs. In Indonesia, we executed a successful drilling program that resulted in a 44% increase in production. The Company has the management talent, technical expertise and financial resources to build on its 2001 successes and grow shareholder value. While 2001 was a difficult year for capital markets, 2002 looks to be a highly rewarding year for Equatorial shareholders.

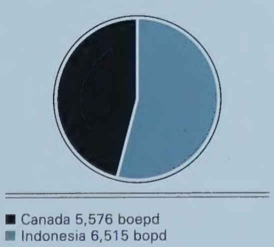
MILESTONES 2001

- Consolidation of Canadian properties into a smaller, more manageable geographic area.
- Canadian proved finding and development costs of $7.53 per boe in 2001.
- Indonesian production levels reached a high of 8,000 barrels per day in 2001.

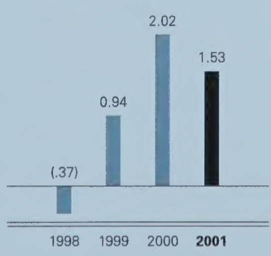
2002+ GOALS

- To increase the underlying value of the Company on a per share basis and to have that value reflected in the stock market.
- In Canada, continued asset rationalization and increased reserve quality with an emphasis on natural gas targets, increased reserve life and decreased operating costs.
- In Indonesia, continued increases in production and reserves.

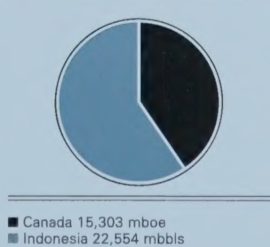
DAILY PRODUCTION



CASH FLOW – DILUTED
per share($)



RESERVES
(proved + 1/2 probable)



THE PRIMARY OBJECTIVE OF MANAGEMENT FOR 2002 IS TO INCREASE THE UNDERLYING VALUE OF THE COMPANY ON A PER SHARE BASIS, AND TO HAVE THE VALUE REFLECTED IN THE MARKET FOR THE COMPANY'S COMMON SHARES.

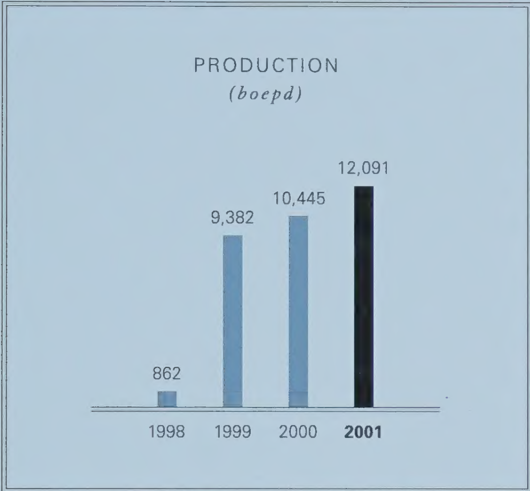
FINANCIAL HIGHLIGHTS

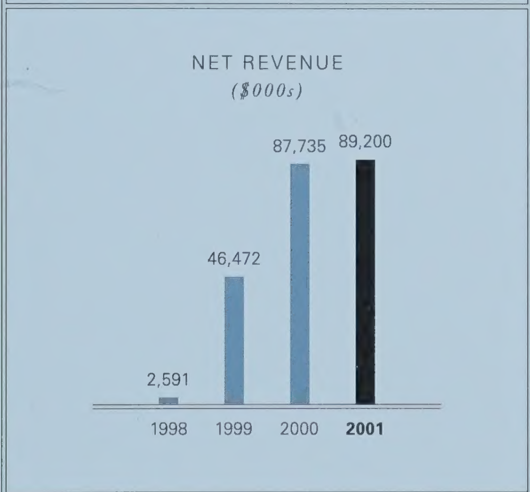
(000s, except per share amounts)	2001	2000
Revenue, net of royalties and government share	**$ 89,200**	$ 87,735
Cash flow from operations	**43,849**	50,478
Net income (loss)	**(8,392)**	14,093
Working capital	**4,637**	7,973
Long-term debt	**51,779**	65,274
Shareholders' equity	**46,205**	42,517
Cash flow per share		
basic	**1.74**	2.62
diluted	**1.53**	2.02
Earnings (loss) per share		
basic	**(0.34)**	0.70
fully diluted	**(0.34)**	0.56

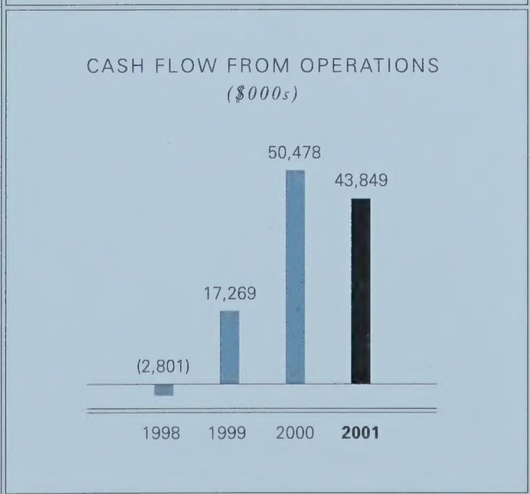
OPERATING HIGHLIGHTS

	Production	Reserves Proved + 1/2 Probable
Canada		
Crude oil and NGLs	2,082 bopd	4,940 mstb
Natural gas	20,960 mcfpd	62.2 bcf
Indonesia		
Crude oil	6,515 bopd	22,554 mstb
Total Company (at 6:1)	12,091 boepd	37,857 mboe

	Gross	Net
Wells		
Canada	509	338
Indonesia	102	102
Total	611	440
Drilling		
Oil	33	40.7
Gas	18	1.6
Dry	15	14.0
Total	66	56.3
Success Rate	77%	75%
Undeveloped Land (acres)	253,000	165,000


PRODUCTION
(boepd)
862
9,382
10,445
12,091
1998
1999
2000
2001


NET REVENUE
($000s)
2,591
46,472
87,735
89,200
1998
1999
2000
2001


CASH FLOW FROM OPERATIONS
($000s)
(2,801)
17,269
50,478
43,849
1998
1999
2000
2001

Fellow Shareholders

PRESIDENT'S *Message*

The past year was tumultuous for Equatorial and its shareholders. Our common shares traded on the Toronto Stock Exchange between a low of $1.55 per share and a high of $4.20 per share. Commodity prices reached highs of US$32.19 WTI for oil and C$13.60 AECO for natural gas, with corresponding lows of US$17.45 and C$2.35. The contemplated sale of our Indonesian assets in the third quarter did not close in the period of uncertainty following the September 11, 2001 tragedy. Further, management changes and a "ceiling test" write-down relating to the carrying value of our Indonesian assets in the third quarter heralded an end to the most turbulent year in the brief history of our Company.

Company production levels, however, reached 12,091 boepd in 2001, a 16% increase over 2000 production of 10,445 and a 29% increase over 1999 production of 9,382 boepd. All of this production growth was generated by our maturing Indonesian asset base. Clearly, the Company's focus on growing Indonesian production has been highly successful. Canadian production averaged 5,576 boepd in 2001. After taking into account the sale of approximately 300 boepd, this daily rate was consistent with 2000 production levels of 5,920 boepd.

In 2001, the positive cash flow generated by our Indonesian operations was sufficient to cover all Indonesian capital expenditures, fund certain of our Canadian drilling and completion activities and provide "seed" capital for new Indonesian opportunities. The ability of our Indonesian operations to be self-funding enables more capital and human resources to be applied to our Canadian asset base. We anticipate a strong year for the Company in 2002.

The Company drilled 66 wells in 2001, 29 in Canada and 37 in Indonesia, resulting in 33 oil wells, 18 gas wells and 15 dry holes. Our success reflects the low-risk nature of the asset base, as well as management's low-risk capital deployment strategy, particularly in Canada. This highly successful approach will continue into 2002.

An important measure of the value of your investment is net asset value ("NAV"). This year, our NAV calculations are presented on an after-tax basis for the Indonesian assets and a pre-tax basis for the Canadian assets. The underlying fiscal regimes in Canada and Indonesia differ, and we believe this presentation best reflects

the actual underlying economic value of the assets. The NAV per share at December 31, 2001 is in the range of $2.78 – $3.61, depending on the discount rate, using escalated pricing assumptions determined by our third party engineers.

Major strides were taken to complete the simplification of the balance sheet and capital structure in 2001. Equatorial was built on very creative counter cyclical acquisitions. However, each deal brought with it unique and complex financing arrangements. During 2001, the Company repaid $17,518,000 of convertible notes and renegotiated US$3,000,000 of contingent, production-based notes, both of which related to the 1998 acquisition of the Sembakung property. In addition, the Company converted the outstanding Series 1 convertible preferred shares relating to the 1999 Canadian asset acquisition into common shares. As a result of these transactions, the Company now has a much more traditional capital structure consisting of debt and common share equity.

CANADA

In Canada, the Company set in motion a plan to consolidate operations into a smaller, more manageable geographic area. During the year the Company disposed of approximately 300 boepd of production that was geographically diverse with excessive per boe operating costs. This transaction also included the disposition of over 200 well bores, resulting in 40% fewer well bores at the end of 2001. The plan to consolidate operations in Canada will continue in 2002, with capital spending plans focused on the eastern and central parts of southern Alberta. Over 80% of the Company's 2002 budget will be spent in our core areas. Our success and sustainability in our core areas is evident by our 2001 finding and development costs of $7.53 per proved boe.

INDONESIA

At Sembakung, the Company successfully drilled and completed eight oil wells in 2001, up from the six wells drilled and completed in 2000. Production levels reached a high of 8,000 bopd during the year. In addition, the Company completed the acquisition and evaluation of a 3-D seismic survey on the Sembakung oilfield. This information revealed a significant potential extension of the field that could materially add to the reserves and production base of the field. The extension will be evaluated by

the drilling of four wells scheduled for the first half of 2002. In 2001, the Company initiated a waterflood pressure maintenance scheme; however, the first injector well did not respond positively to water injection and the remote location of the well made remedial action difficult. Accordingly, another well is being converted to an injector well. A third Foremost track vehicle is also planned to advance road and pad construction.

Operations at the Pilona TAC continued with the drilling of 22 successful oil wells in 2001. In 2002, more emphasis will be placed on the deeper producing formations at the Sengkuang and Tanjung Lontar fields at about 4,000 feet. Production from new wells drilled into these two fields have lower decline rates and higher, longer-life production than the shallow wells drilled in 2000 and 2001 at Arahan Banjarsari. We anticipate that our 2002 drilling program will offset natural production declines and allow us to maintain production levels from Pilona in the 1,000 – 1,500 bopd range.

Indonesian finding and development costs, including initial acquisition costs, averaged $8.16 per boe of proved reserves and $4.61 per boe of proved plus 1/2 probable reserves over the last four years. The 2001 capital program was designed to accelerate production and cash flow by developing previously booked proved reserves. Therefore, the 2001 finding and development cost calculation for Indonesia should consider that we were in the development phase with our existing proved reserves and not targeting reserve additions as we did in the past.

We will continue to allocate significant resources to Indonesia in 2002. We entertained a sale of our Indonesian operations last year because we felt the proposed price was a good business proposition for our shareholders. When the transaction failed to materialize, we immediately planned for additional growth in Indonesia. We will spend about US$20 million developing our properties in South Sumatra and N.E. Kalimantan this year and earn a respectable rate of return for our efforts.

Politically, President Megawati Sukarnoputri's government in Jakarta has made significant strides in recent weeks to improve security for international investors. The government is also implementing "regional autonomy," a process by which a significant portion of the revenues from natural resources will be returned to the

outlying provinces. "Regional autonomy" is further evidence of the Indonesian government's efforts to transcend the inequalities of the past.

FINANCIAL RESULTS

Revenues of $136,162,000 were a 6% increase over 2000 revenues of $128,582,000, while cash flow of $43,849,000 in 2001 represented a 13% decrease over 2000 cash flow of $50,478,000. Cash flow per share in 2001 was $1.74 per share and $1.53 per share on a diluted basis.

Company debt, net of working capital, declined to $47,100,000 at the end of 2001, down $10,201,000 from 2000 debt levels of $57,301,000. Debt is now at approximately 1x consolidated cash flow.

The Company has an undesirable derivative position that has caused a significant loss in revenue over the past two years. The derivative position was necessary in order to obtain the bank loan associated with the 1999 Canadian asset acquisition. Management has been active in monitoring and trading around the existing core position. The passage of time is mitigating the size and impact of the existing derivatives, the largest of which has little more than one year remaining.

OBJECTIVES FOR 2002

The primary objective of management for 2002 is to increase the underlying value of the Company on a per share basis, and to have that value reflected in the market for the Company's common shares.

In Canada, continued asset rationalization and increases in the quality of reserves are key objectives. Projects planned for 2002 are designed to increase our reserve life index and decrease operating costs. We also plan to increase the natural gas content of our Canadian production to 60% in 2002. Over 90% of our 2002 budget is dedicated to natural gas targets.

In Indonesia, we plan continuous drilling at Sembakung in 2002. We commenced drilling the first well on the first southern drilling pad in early March. When it reached total depth, it was cased as an oil well. We plan to drill one more well on this

pad and then move the rig to the second southern drilling pad to test a previously undrilled structure that, if successful, will add material reserves and production.

Your Company now has an excellent inventory of upstream opportunities in Indonesia because of its continued operating presence in Indonesia on a day-to-day basis and its reputation as a Contractor of merit with PERTAMINA, the national oil company of the Republic of Indonesia. We are working with a major Canadian bank to source capital in S.E. Asia and Europe to finance these opportunities. After a five-year moratorium, many Western financial institutions have recently renewed their interest in Indonesia. We are well positioned with our inventory of superior "upstream" opportunities in Indonesia should these financing institutions commence providing capital to oil companies at competitive rates.

2001 was a challenging year for both the staff and shareholders of Equatorial. I would like to thank the officers and employees of the Company for their hard work and dedication this year. The Company has a full complement of professional staff in Canada and Indonesia and a renewed sense of drive and dedication towards building value. Your continued support of our efforts is very much appreciated.

Yours truly,

JOHN R. ROONEY
President and
Chief Executive Officer

MARCH 27, 2002

CANADA

Equatorial's Canadian reserve base is 68% natural gas and 32% oil and NGLs (on a 6:1 conversion basis). In addition, the Corporation owns 165,000 net acres of undeveloped land. Operated properties account for 80% of production and 87% of reserves. Excluding the Kaybob unit interest, operated properties account for 90% of production and 94% of reserves. The Corporation's average working interest for reserves is 56% and 63% for lands.

During 2001, the Corporation drilled 29 gross (19 net) wells, resulting in 3 gross (2 net) oil wells, 18 gross (11 net) gas wells and 8 gross (6 net) dry holes for a total of 13 net producing wells. Average Canadian production volume for the year was 5,576 boepd, of which 63% was natural gas and 37% was oil and NGLs.

The following is a description of the Corporation's principal producing and exploration properties in western Canada. Prior to the major property acquisition from Conoco Canada Resources Limited in 1999, the Corporation had no properties in western Canada.

Core Properties

During 2001, the Corporation focused its Canadian activities on eight high production volume properties. The core operated properties of Berry, Bigoray, Gordondale, Saskatchewan, Malmo, S.E. Alberta, and Willesden Green and the non-operated Kaybob Unit No. 2 generated 83% of Canadian production and represent 91% of Canadian boe reserve volumes. The development of a Second White Specs ("SWS") play in S.E. Alberta and a Mannville channel play in Berry represented the Corporation's highest success activities during the year. Both of these areas will continue to be a major focus for 2002 activity.

Based on the success of the Corporation's activities in the S.E. and central Alberta areas, the Corporation's core properties have been redefined to reflect its focus on development and exploration programs in Berry, Bigoray, Malmo, S.E. Alberta and Willesden Green. Consistent with this focus, all other areas are non-core and are potential swap or disposition candidates. Proceeds from dispositions of non-core properties will be redirected to development activities on these five core properties.

In 2001, the Corporation sold approximately 300 boepd of scattered, low productivity and high operating cost production, as the first phase of consolidating its activities in a smaller geographic area. This consolidation is expected to continue in 2002.

Berry

Equatorial holds an average working interest of 75% in the Berry property, which is located approximately 150 kilometres northeast of Calgary. The Company drilled five wells in 2001, resulting in five gas wells. Average initial production from each well was approximately 1.0 mmcfpd of gas and 30 bopd. Over the past year, Equatorial has been very successful in identifying these zones with the use of three-dimensional seismic technology. The Corporation drilled five successful Mannville Channel wells and upgraded its processing capacity in the area during the year. Production is from a number of zones within the Mannville Group and averaged 141 bopd and 3.2 mmcfpd of gas during the year. Equatorial anticipates drilling a minimum of six follow-up locations in 2002.

Bigoray

The Bigoray property is located approximately 300 kilometres northwest of Calgary. Working interests vary from 25% to 100%, with the majority of the lands 100% owned.

There are 15 (9 net) producing wells on the Bigoray property. They contain long-life reserves and produce sweet gas from the Glauconite and Ostracod formations. Gas produced from the Bigoray property is rich in NGLs and is processed at a third-party facility, which provides deep-cut processing capable of ethane plus recovery. Production averaged 231 bpd of NGLs and 4.3 mmcfpd of gas during the year. Equatorial plans a number of additional restimulation candidates in this area in 2002.

Malmo

Equatorial holds working interests between 83% and 100% in the Malmo property, located approximately 65 kilometres northeast of Red Deer, Alberta. Production averaged 2.4 mmcfpd of gas, primarily from the Belly River Zone. The 2001 program included the drilling of six gas wells. Activity in 2002 is expected to concentrate on the development of shallow Upper Belly River sands.

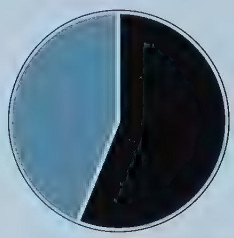
CANADIAN PRODUCTION

- Operated 80%
- Non-operated 20%

CANADIAN DAILY PRODUCTION

- Oil 2,082 bopd
- Natural Gas (at 6:1) 3,493 boepd

CANADIAN LAND (NET)



■ Undeveloped 165,000 acres
■ Developed 129,000 acres

S.E. Alberta

Equatorial holds an approximately 96% working interest in the Grassy, Grand Forks, Hays, Enchant and Winnifred producing areas, collectively referred to as "S.E. Alberta." The majority of the lands within the S.E. Alberta area are located approximately 200 kilometres southeast of Calgary, with production coming from the Sawtooth, Glauconite, Bow Island and SWS formations. Total production in the area averaged 553 bopd and 1.7 mmcfpd of gas during the year.

The main focus of the Corporation's activities in 2001 was in the Winnifred area where nine suspended wells were recompleted in the SWS zone and two other suspended wells were recompleted in the Bow Island Formation. The Corporation's gas gathering and processing facilities were upgraded to accommodate increased production. This activity added approximately 2.0 mmcfpd to the area production and identified the potential for further development of both plays.

The Corporation owns over 60 sections of land in the Winnifred area and activity in 2002 will consist of drilling eight wells in the early part of the year in order to confirm the productivity of the SWS zone, which will be followed up with a larger program in the fall, targeting both the SWS and the Bow Island formations.

Willesden Green

Equatorial holds interests ranging from 53% to 100% in the Willesden Green area, located 50 kilometres west of Red Deer, Alberta. Production from this property averaged 121 bopd and 1.5 mmcfpd of gas during the year. Activity during 2001 consisted of recompleting three suspended Cardium Formation wells and the construction of a compressor station. Plans for 2002 include recompletion work in the Cardium and other uphole horizons.

Non-Core Properties

The Canadian non-core properties provide significant cash flow at relatively low operating costs. Only a small amount of development and no exploration activities are anticipated for these areas in 2002 and Equatorial will pursue swapping these properties for properties within its core areas. These properties represent 39% of Canadian production and 34% of Canadian reserve volumes.

CANADIAN RESERVES BY CATEGORY
(at 6:1)

■ Proved Producing 9,754 mboe
■ Proved Non-producing 3,255 mboe
■ 1/2 Probable 2,294 mboe

CANADIAN RESERVES BY PRODUCT
(Proved + 1/2 probable)

■ Natural Gas (at 6:1) 10,363 mboe
■ Oil 4,940 mboe

The most significant of these properties are Gordondale, Kaybob and Saskatchewan. The remaining non-core properties are located in N.E. Alberta.

Gordondale

Equatorial holds various interests, ranging from 6.25% to 100% in the Gordondale area. This property is located in N.W. Alberta, approximately 300 kilometres northwest of Edmonton, Alberta. Production in the area averaged 679 boepd during the year. The property contains both oil and gas reserves, with oil production coming from wells in the Halfway "K" oil pool and gas production from a number of different formations.

Kaybob South Triassic Unit No. 2

Equatorial owns a 29.94% non-operated working interest in the Kaybob South Triassic Unit No. 2, approximately 250 kilometres northwest of Edmonton, Alberta. Production consists of light, slightly sour, 42 degree API gravity oil, associated gas and NGLs. The unit commenced production in 1967 and is currently under waterflood. Production is from 31 (10 net) oil wells in the Montney Formation with pressure support provided by 13 water injectors in a peripheral waterflood scheme. Total production averaged 444 bopd during the year.

Since December 1998, three successful horizontal re-entry wells have been drilled. Additional drilling potential has been identified. Re-entry drilling has proved effective in reducing production declines and tapping into undepleted portions of the reservoir.

Saskatchewan

The Saskatchewan area consists primarily of oil properties in Wauchope and Arcola, as well as a number of smaller properties, all in S.E. Saskatchewan. Total production from the area averaged 291 boepd during the year.

Wauchope is approximately 130 kilometres southeast of Regina. Equatorial holds a 97% working interest in Wauchope, which produced 160 boepd during 2001. The pool has been developed with both horizontal and vertical wells. The Arcola property is approximately 200 kilometres southeast of Regina. Equatorial holds a 50% working interest in the property, which produced 80 boepd during 2001. Both properties have been developed extensively. They have long life reserves and relatively low decline rates.

Other Non-Core Properties

The Corporation's other non-core properties are scattered throughout Alberta, N.E. British Columbia and S.W. Saskatchewan. Production from these properties averaged 765 boepd in 2001. All of these properties are considered swap or disposition candidates and it is expected that many of them will be divested during 2002.

INDONESIA

The Indonesian reserve base is 100% oil and 100% operated by Equatorial. Operations in Indonesia are conducted through production sharing arrangements called "Technical Assistance Contracts" ("TACs") with PERTIMINA, the state oil and gas company of Indonesia. The oil and mineral rights covered by the TACs are retained 100% by PERTIMINA for Indonesia, with Equatorial owning a contractual interest in oil produced in each contract area. The Corporation has two TACs with PERTIMINA.

Average Indonesian production volume for the year was 6,515 bopd, which represents approximately 54% of the total Equatorial 2001 boe production.

Sembakung

Equatorial has an 80% interest in the Sembakung oilfield in northeast Kalimantan, Indonesia. In 2001, Equatorial drilled and completed eight wells at Sembakung, resulting in eight oil wells.

Under the terms of the joint venture agreement with the 20% Indonesian partner, Equatorial is entitled to 100% of net operating profits until all of Equatorial's capital, advances and accrued interest are recovered. At December 31, 2001, the total amount due to the Corporation to be recovered prior to the partner participating in operating profits was US$11,761,000.

The reservoir quality at Sembakung is excellent, with porosity ranging from approximately 15% to 30% and permeability in the 200 mD to 2,000 mD range. The crude oil is 37 degrees API gravity with very low wax content and no sulfur. The reservoir is comprised of a series of stacked deltaic sands of the Miocene Tabul Formation, in which 33 separate reservoir zones are identified. The field is very shallow, with the upper reservoirs at 450 metres and the base of the currently producing zones at approximately 1,000 metres. The field has a number of discreet gas caps recognized from logging.

In addition to the discovery of the existing productive reservoirs, Atlantic Richfield Company ("ARCO"), the previous holder of the Sembakung contract area, drilled two deeper wells that encountered gas and significant reservoir sands. Existing two-dimensional seismic data showed evidence of untested reservoir potential. Accord-

ingly, three-dimensional seismic data was acquired and processed in 2001. The interpretation of this data suggests significant extensional drilling potential to the south of the main Sembakung field area.

The main Sembakung block was sparsely drilled by Arco on 100 acre well spacing and Equatorial's plan is to reduce this to a more appropriate drainage spacing of approximately 30 acres. Since purchasing the property in 1998, Equatorial has completed a "floating road," built drilling pads and implemented a directional drilling program. The first well drilled by Equatorial was spudded on December 5, 1999 and the Company has drilled continuously since that time. A total of six wells were drilled in 2000 and eight wells were drilled in 2001.

Over the past two years a significant number of uncompleted zones have been identified in the 19 wells drilled prior to Equatorial taking over the operation of the field. Accordingly, part of the development plan for 2002 includes completing bypassed zones.

Equatorial is in the process of implementing an enhanced recovery program at the Sembakung oilfield that will convert probable reserves into proved reserves over time. Water injection was initiated during 2001, but satisfactory injection rates were not attained. Restricted access to the injector well bore made remedial efforts difficult. Consequently, the well was put back on production and a different well is being converted to an injector well. The technical data indicates that an enhanced recovery scheme will be successful and that probable reserves will be moved to proved; however, it is difficult to accurately predict when this will occur.

From a drilling perspective, the main focus for 2002 will be on the south Sembakung area. Indications from the three-dimensional seismic program suggest two main targets for drilling. The first drilling target will delineate the distribution of reserves in the main producing Tabul Formation in a structural extension to the main Sembakung anticline. This program commenced in late 2001 with the construction of an initial two well drilling pad in the area between the existing producing wells, SBK-4 and E-SBK-2. The first of these wells has been drilled to total depth and was completed as an oil well in March 2002. If these two wells prove successful, the pad will be extended and a further four to five wells will be drilled in that area.

The second drilling target is an exploration well to test a new concept also developed from the three-dimensional seismic data. It was recognized from the data that the Tabul reservoirs are severely eroded to the south and that a new sequence was developed above this unconformity in the southwest corner of the block. A second southern drilling pad is currently being constructed to drill a well into this feature. It is anticipated that this well will be completed by the end of the second quarter. Results from this well will determine if additional pad construction will be required to exploit any potential discovery.

Tanjung Lontar

The Pilona TAC comprises four old oilfields at the southern end of the island of Sumatra. In 2001, Equatorial drilled 29 wells within the Pilona concession, resulting in 22 oil wells, five suspended wells and two dry holes.

The two northerly fields, Tanjung Lontar and Sengkuang, have productive horizons at 800 – 1000 metres in depth. The Arahan and Banjarsari fields have reservoirs generally shallower than 300 metres. All are located in the Palembang Sub-Basin, which is the southeastern part of the South Sumatra Basin.

All the fields produce very light sweet crude (47 degree API) from a series of stacked deltaic sands of the Muara Enim Formation. The reservoirs have excellent porosity and permeability characteristics, with porosities of 20% to 28% and permeabilities ranging from approximately 200 mD to over 1,000 mD. A pipeline has been constructed to gather oil from the Pilona TACs productive pools for delivery to a PERTIMINA oil battery.

Equatorial initiated development of the fields in June 1997 and since that time close to 70 wells have been drilled on the property. During 2001, development drilling of the shallow Banjarsari pool continued to the point where delineation drilling of the pool has been almost completed. Only three wells remain to be drilled in 2002. Also in Banjarsari, Equatorial drilled a number of very shallow wells (less than 150 metres depth) to determine the potential remaining in these historically productive layers. This program met with mixed success and confirmed that the reservoirs around the 300 metres depth range have the most potential.

In the Arahan pool, across the Lematang river from Banjarsari, five wells were completed during 2001, all of which were successful oil wells. Based on this success, another five wells will be drilled in 2002 to delineate this pool.

Drilling in the Tanjung Lontar and Sengkuang fields was also reinitiated during 2001. These fields have reservoir targets at a depth of 600 and 800 metres, respectively. Two wells were drilled in each of these fields and all were successful in adding significant long-term stable production volumes. One of the wells at Tanjung Lontar encountered a flowing oil zone not previously produced in this field. Based on the 2001 results, two more wells in each of the Sengkuang and Tanjung Lontar fields will be drilled in 2002.

The long-term expectation for the Pilona TAC is to maintain the daily production volumes in the 1,000 bopd to 1,500 bopd range.

SUMMARY OF RESERVE VALUES
and volumes

	Reserves Oil & NGLs mstb	Reserves Natural Gas mmcf	0%	10%	15%	20%
Canada			Before Tax Net Present Values ($000s)			
Total proved	4,174	53,008	$ 174,179	$ 110,889	$ 94,477	$ 82,556
1/2 probable	766	9,172	32,196	15,326	11,956	9,731
Total Canada	4,940	62,180	206,375	126,215	106,433	92,287
Indonesia			After Tax Net Present Values (1) ($000s)			
Total proved	11,820	–	$ 23,416	$ 18,298	$ 16,522	$ 15,074
1/2 probable	10,734	–	32,794	16,564	12,005	8,749
Total Indonesia	22,554	–	56,210	34,862	28,527	23,823
Total Company						
Total proved	15,994	53,008	$ 197,595	$ 129,187	$ 110,999	$ 97,630
1/2 probable	11,500	9,172	64,990	31,890	23,961	18,480
Total Company	27,494	62,180	$ 262,585	$ 161,077	$ 134,960	$ 116,110

(1) Equatorial is incurring cash Indonesian income taxes. Unlike Canada, Indonesian contracts are "ring fenced" and tax pools from sources other than the direct expenses of each contract cannot be applied against the cash flows of that contract.

PRODUCTION AND RESERVES
by location

	2001 Average Production Rates			Oil & NGLs Reserve Volumes (mbbls)			Natural Gas Reserve Volumes (mmcf)		
Property	Oil & NGLs bopd	Natural Gas mcfpd	boe (6:1)	Proved	1/2 Probable	Total	Proved	1/2 Probable	Total
Berry	141	3,188	672	210	39	249	8,094	2,272	10,366
Bigoray	231	4,330	953	781	138	919	13,878	2,399	16,277
Gordondale	152	3,160	679	602	52	654	6,755	1,062	7,817
Kaybob	444	–	444	1,043	204	1,247	459	88	547
Malmo	1	2,448	409	–	–	–	2,701	387	3,088
Saskatchewan	285	38	291	411	61	472	76	12	88
S.E. Alberta	553	1,685	834	638	242	880	10,714	1,468	12,182
Willesden Green	121	1,470	366	294	28	322	4,247	440	4,687
Other	16	4,494	765	195	2	197	6,084	1,047	7,131
Sold Properties	138	148	164	–	–	–	–	–	–
Total Canada	2,082	20,960	5,576	4,174	766	4,940	53,008	9,172	62,180
Sembakung	5,293	–	5,293	11,334	10,635	21,969	–	–	–
Tanjung Lontar	1,222	–	1,222	486	99	585	–	–	–
Total Indonesia	6,515	–	6,515	11,820	10,734	22,554	–	–	–
Total Company	8,597	20,960	**12,091**	15,994	11,500	**27,494**	53,008	9,172	**62,180**

LAND HOLDINGS
– December 31, 2001

	Gross Developed Acres	Net Developed Acres	Average Working Interest	Gross Undeveloped Acres	Net Undeveloped Acres	Average Working Interest
Canada						
Berry	41,794	24,171	58	27,371	17,865	65
Bigoray	11,386	6,897	61	8,382	3,949	47
Gordondale	26,099	13,007	50	32,261	14,245	44
Kaybob	11,070	3,025	27	3,954	1,707	43
Malmo	17,302	13,299	77	17,823	15,288	86
Saskatchewan	6,533	3,662	56	67,831	58,909	87
S.E. Alberta	47,784	34,137	71	16,756	10,134	60
Willisden Green	5,874	2,360	40	1,581	1,043	66
Other	51,495	28,689	56	76,317	42,301	55
Total Company	219,337	129,247	59	252,276	165,441	66

NET ASSET VALUE
– December 31, 2001

	15% PV	10% PV
Total proved plus 1/2 probable values (000s)		
Canada – before tax	$106,500	$ 126,215
Indonesia – after tax *(1)*	28,527	34,862
	135,027	161,077
Undeveloped land – Canada	13,000	13,000
	148,027	174,077
Conversion of stock options into cash	1,500	1,500
Debt, net of working capital	(47,142)	(47,142)
Hedge – mark to market *(2)*	(10,900)	(11,400)
Other	(3,200)	(3,200)
Net asset value	88,285	113,835
Net asset value per share (diluted)	**$ 2.79**	**$ 3.61**

(1) Equatorial is incurring cash Indonesian income taxes. Unlike Canada, Indonesian contracts are "ring fenced" and tax pools from sources other than the direct expenses of each contract cannot be applied against the cash flows of that contract.

(2) Based on pricing assumptions used by Equatorial's independent reserve engineers.

FINDING & DEVELOPMENT
Costs

	2001	2000	4 Year Total
Capital expenditures (000s)			
Acquisitions	$ 1,159	$ 1,982	$ 107,797
Exploration	7,029	5,446	16,750
Development	42,626	33,807	94,478
Other	35	261	1,262
	50,849	41,496	220,287
Net proved reserve additions (mboe, gas converted at 6:1)			
Acquisitions	186	211	28,449
Discoveries	2,375	846	5,681
Revisions	1,285	2,000	(1,030)
	3,846	3,057	33,100
Net proved plus 1/2 probable reserve additions (mboe, gas converted at 6:1)			
Acquisitions	199	220	42,882
Discoveries	2,769	1,381	6,785
Revisions	(543)	1,414	(4,577)
	2,425	3,015	45,090

			4 Year Average
Total Company			
Finding and development costs – proved	$ 13.22	$ 13.58	$ 6.66
Finding and development costs – proved plus 1/2 probable	20.97	13.76	4.89
Canada			
Finding and development costs – proved	7.53	10.53	5.75
Finding and development costs – proved plus 1/2 probable	12.45	8.78	5.15
Indonesia			
Finding and development costs – proved	26.11	17.03	8.16
Finding and development costs – proved plus 1/2 probable	37.90	22.85	4.61

NETBACKS

	2001			2000
	Canada	Indonesia	Total	Total
Realized price				
Oil/barrel	$ 31.80	$ 36.30	$ 35.36	$ 41.51
NGLs/barrel	29.23	–	29.23	29.83
Natural gas/mcf	5.56	–	5.56	5.55
Royalties and government share				
Oil/barrel	$ 6.21	$ 13.45	$ 11.94	$ 13.06
NGLs/barrel	9.76	–	9.76	9.12
Natural gas/mcf	1.28	–	1.28	1.08
Operating costs				
Oil/barrel	$ 8.78	$ 7.75	$ 7.97	$ 7.42
NGLs/barrel	5.54	–	5.54	5.29
Natural gas/mcf	0.99	–	0.99	0.89
Netbacks				
Oil/barrel	$ 16.81	$ 15.10	$ 15.45	$ 21.03
NGLs/barrel	13.93	–	13.93	15.42
Natural gas/mcf	3.29	–	3.29	3.58

Management's discussion and analysis of financial conditions and results of operations ("MD&A") should be read in conjunction with the Consolidated Financial Statements and related notes contained elsewhere in this Annual Report. The calculation of boe and boepd is based on a conversion rate of six thousand cubic feet of natural gas for one boe.

RESULTS OF OPERATIONS

Production

Volumes	2001 Canada	2001 Indonesia	2001 Total	2000 Canada	2000 Indonesia	2000 Total
Oil and natural gas liquids *(bopd)*	**2,082**	**6,515**	**8,597**	2,457	4,525	6,982
Natural gas *(mcfpd)*	**20,960**	**–**	**20,960**	20,779	–	20,779
Oil equivalent *(boepd) (6:1)*	**5,576**	**6,515**	**12,091**	5,920	4,525	10,445
Total boe produced *(6:1)*	**2,035,201**	**2,378,037**	**4,413,238**	2,161,027	1,651,545	3,812,572

Production increased 16% from 10,445 boepd in 2000 to 12,091 boepd in 2001.

The production gains were primarily related to the successful Indonesian drilling program, which resulted in a 44% increase in Indonesian production from 4,525 bopd in 2000 to 6,515 bopd in 2001. In Canada, after taking into account the sale of 300 boepd, normal production declines have been offset by successful drilling.

Revenues/Royalties/Government Share

Summary	2001 Canada	2001 Indonesia	2001 Total	2000 Canada	2000 Indonesia	2000 Total
Commodity prices						
Oil and liquids *(per barrel)*	**$ 31.35**	**$ 36.30**	**$ 35.10**	$ 37.50	$ 42.51	$ 40.75
Natural gas *(per mcf)*	**5.56**	**–**	**5.56**	5.55	–	5.55
Revenue – before hedge *($000s)*	**66,405**	**86,315**	**152,720**	75,753	70,205	145,958
Royalty/government share	**14,981**	**31,981**	**46,962**	15,376	25,471	40,847
Royalty/government share *(%)*	**23%**	**37%**	**31%**	20%	36%	28%

Oil and natural gas revenues in the income statement are net of hedging losses of $16,558,000 (2000 – $17,376,000). The decline in hedge loss is due to lower oil prices and higher prices in the related derivative contracts in 2001. The Corporation sells its commodities at market prices and settles the hedge positions with cash on a monthly basis.

Net of hedging, revenue increased 6% from $128,582,000 in 2000 to $136,162,000 in 2001, primarily due to increased volumes in Indonesia.

Royalties are a combination of freehold, crown and overriding royalties in Canada and government share in Indonesia.

Royalties in Canada decreased from $15,376,000 in 2000 to $14,981,000 in 2001 due to decreased Canadian gross revenues. However, the Canadian royalty rate increased from 20% of Canadian gross revenues in 2000 to 23% in 2001 due to dispositions of low productivity and high operating cost wells that had relatively low royalty rates.

Government share in Indonesia represents the entitlement of the Indonesian government to a portion of the Corporation's production, and is recorded using rates in effect under the terms of contracts at the time of production.

Included in the calculation of government share in the Sembakung TAC is a concept of Non-Shareable Oil ("NSO"). NSO is a calculated amount of total production that is not subject to sharing, although the Corporation is responsible for operations relating to this production. The Indonesian government pays for that portion of operating costs relating to NSO, but is not responsible for any capital costs. NSO volumes in 2001 were 1,044 bopd, compared to 1,192 bopd in 2000. The NSO volume declines, under the terms of the TAC, at 13.3% annually.

In addition to NSO at Sembakung, government share includes a portion of the production from each TAC based upon the terms of the contract. Under the terms of the TACs, the Corporation is entitled to use gross proceeds of production of shareable oil to recover substantially all of the non-capital costs incurred in the development of the contract area as well as current year depreciation for capital costs and any costs unrecovered in prior years. The maximum cost recovery is 80% of shareable oil revenue. After costs are recovered, the Corporation's share of before-tax revenue reverts to approximately 29%.

Government share in Indonesia was $31,981,000 or 37% of revenues in 2001, which is comparable, on a percentage basis, to $25,471,000 or 36% in 2000. Government share increased during 2001 as production volumes increased. Based on expected oil prices and budgeted capital expenditures, this percentage is expected to decline in 2002.

Write-Down of Petroleum and Natural Gas Interests

The Corporation is in the process of implementing an enhanced recovery program at the Sembakung oilfield that will convert probable reserves into proved reserves over time. The Corporation initiated water injection during 2001, but satisfactory injection rates were not attained. Restricted access to the injector well bore made remedial efforts difficult. Consequently, the well was put back on production and a different well is being converted to an injector. The technical data indicates that an enhanced recovery scheme will be successful and that probable reserves will be moved to proved; however, it is difficult to accurately predict when this will occur.

Given the unpredictability of the timing of these events, all capitalized costs in Indonesia were subjected to the impairment test required by the full-cost method of accounting for oil and gas operations. The inclusion of costs relating to probable reserves that were previously excluded (see Notes 2(d) and 3 to the Consolidated Financial Statements), combined with lower oil prices, resulted in a ceiling test write-down of the Corporation's Indonesian properties of $30,135,000 less a future tax recovery of $15,027,000 for a net after-tax write-down of $15,108,000.

Reserve volumes of our Indonesian properties are unaffected by these events.

Operating Costs

Summary	Canada 2001	Indonesia 2001	Total 2001	Canada 2000	Indonesia 2000	Total 2000
Operating costs *($000s)*	**13,265**	**18,434**	**31,699**	13,142	12,168	25,310
Cost per boe	**6.52**	**7.75**	**7.18**	6.08	7.37	6.64

The increase in operating costs from $25,310,000 in 2000 to $31,699,000 in 2001 is primarily due to increased volumes in Indonesia. On a per boe basis, the increase from $6.64 per boe in 2000 to $7.18 per boe in 2001 relates to an increase in the cost of services in Canada and Indonesia.

In Canada, the Corporation sold 300 boepd of low productivity, high operating cost wells in 2001. The impact of this, combined with continued property consolidation is expected to lower per boe operating costs in 2002.

In Indonesia, under the terms of the TACs, the Corporation has the right to recover all operating costs in each TAC against available revenues generated by the TAC. Operating costs are defined as current year non-capital costs, current year depreciation on capital costs and current year allowed recovery of prior years' unrecovered operating costs. The recovery of operating costs relates to 100% of the Shareable Oil and is reflected in the Corporation's share of revenues. Operating costs relating to NSO are paid by the government and are not included in the Corporation's revenues or expenses.

Administrative Expenses

Summary	Canada 2001	Indonesia 2001	Total 2001	Canada 2000	Indonesia 2000	Total 2000
Gross *($000s)*	**9,086**	**3,163**	**12,249**	7,147	2,218	9,365
Allocated to						
Capital projects	**1,779**	**697**	**2,476**	1,794	347	2,141
Operating projects	**153**	**–**	**153**	132	–	132
Third-party recoveries	**1,105**	**992**	**2,097**	608	768	1,376
	6,049	**1,474**	**7,523**	4,613	1,103	5,716
Cost per boe ($)						
Gross	**4.46**	**1.33**	**2.78**	3.31	1.34	2.46
Net	**2.97**	**0.62**	**1.70**	2.13	0.67	1.50

Administrative expenses increased from $5,716,000 in 2000 to $7,523,000 in 2001. In 2001, the Corporation incurred one-time charges of approximately $2,000,000 related to the termination of its Indonesian asset sale and to management changes. If 2001 administrative costs are adjusted for the one-time charges, the per boe amounts decreased from $1.50 in 2000 to $1.24 in 2001, which reflects lower overall staff levels.

Depletion, Depreciation and Site Restoration

	2001			2000		
Summary	Canada	Indonesia	Total	Canada	Indonesia	Total
Depletion & depreciation *($000s)*	**9,443**	**18,537**	**27,980**	8,884	11,574	20,458
Site restoration	**822**	**–**	**822**	1,180	–	1,180
	10,265	**18,537**	**28,802**	10,064	11,574	21,638
Cost per boe						
Depletion & depreciation	**4.64**	**7.80**	**6.34**	4.11	7.01	5.37
Site restoration	**0.40**	**–**	**0.19**	0.55	–	0.31
	5.04	**7.80**	**6.53**	4.66	7.01	5.68

Depletion, depreciation and site restoration increased from $21,638,000 in 2000 to $28,802,000 in 2001. On a per boe basis, depletion, depreciation and site restoration was $5.68 in 2000 and $6.53 in 2001. The low rates in the 2000 period reflect the low cost of the Corporation's 1999 and 1998 acquisitions. Subsequent development expenditures relating to proved reserves resulted in a higher per barrel depletion expense in 2001.

Site restoration decreased on a per boe basis from $0.55 in 2000 to $0.40 in 2001 because Canadian properties with high future site restoration costs were sold during the year. The Corporation has been actively reclaiming abandoned well sites as part of normal operations.

In 2002, depletion will reflect the success of the Corporation's capital expenditure programs and the associated cost of booking proved reserves.

Taxes

Most of the $5,782,000 tax recovery in 2001 relates to a recovery of $15,027,000 due to the write-down of petroleum and natural gas interests.

In Canada, estimated tax pools at December 31, 2001 were $71,800,000, of which non-capital losses are approximately $12,700,000. Depending on commodity prices and capital investment, the Corporation may be cash taxable by 2003.

In Indonesia, cash taxes of $1,203,000 were incurred in 2001. As production volumes increased, the resulting revenue was sufficient to allow for recovery of cost pools during the year. When cost pools exist, they can be applied to income to defer cash taxes; however, when they have been recovered, cash taxes result. As Indonesian production volumes continue to increase, and depending on oil prices and the size and timing of capital investment, it is expected that Indonesian cash taxes will continue to be incurred in 2002.

Net Earnings

The Corporation recorded a net loss of $8,392,000 ($0.34 per diluted share) for 2001 as compared to net earnings of $14,093,000 in 2000 ($0.56 per diluted share). Without the $15,108,000 net write-down of petroleum and natural gas interests, the Corporation would have experienced 2001 earnings of $6,716,000 ($0.23 per diluted share) compared to 2000 earnings of $14,093,000 ($0.56 per diluted share). The decrease in earnings per share is attributable to lower oil prices, slightly higher Canadian and Indonesian royalties, increased depletion per barrel, and one-time administrative charges incurred during the year.

In 2001, the Corporation retroactively adopted, with all prior periods restated, the new accounting recommendation of the Canadian Institute of Chartered Accountants, "Earnings Per Share." As a result of this change, the treasury stock method is used instead of the imputed interest method to determine the dilutive effect of stock options and warrants.

LIQUIDITY AND CAPITAL RESOURCES

During 2001, the Corporation decreased debt and simplified its capital structure.

Long-Term Debt

The Corporation ended 2001 with $47,100,000 of debt, net of working capital, compared to $57,301,000 at the end of 2000. Cash flow from high commodity prices in the first half of the year, along with proceeds from two common share equity issues allowed the Corporation to repay its US dollar notes of $17,518,000 prior to their maturity in 2001.

As part of the consideration for the purchase of the Sembakung TAC in 1998, the Corporation issued a contingent note for US$3,000,000 that required payments of US$1,000,000 upon reaching each of the production targets of 7,500 bopd, 10,000 bopd and 12,000 bopd. Each payment, together with interest accruing at prime plus 3% from September 14, 1998, was due within 30 days of attaining the production target.

Management believed the Corporation was likely to reach the first 7,500 bopd production target in the near future. To limit the size of this obligation, the Corporation negotiated the replacement of the contingent note with a new US$1,500,000 term note. In so doing, the Corporation crystallized the amount of the obligation, reduced the interest rate to 4%, and fixed the maturity date to January 1, 2004.

At December 31, 2001, the Corporation had $40,000,000 drawn on a revolving bank line with a current borrowing base of $48,000,000. The undrawn portion of the line may be used for both short-term and long-term Canadian capital requirements.

Equity

During 2001, the Corporation completed two private placements and issued 4,850,000 common shares for gross proceeds of $12,587,500. In addition, on May 29, 2001, all of the Series 1 Convertible Preferred Shares were converted into 5,283,550 common shares.

Cash Flow

Cash flow from operations decreased 13% from $50,478,000 in 2000 to $43,849,000 in 2001, or from $2.02 to $1.53 per diluted share. The decrease is due to lower oil prices, slightly higher Canadian and Indonesian royalties, one-time administrative charges, and cash income taxes in Indonesia.

Working Capital

The Corporation had $7,702,000 in cash and $4,637,000 in working capital at December 31, 2001. In addition, the Corporation had $40,000,000 drawn at year end on a revolving bank line with a current borrowing base of $48,000,000. These amounts are expected to be adequate for the size and nature of the Corporation's activities.

Capital Investing and Finding Costs

The Corporation's 2001 capital expenditure budget was approximately $50,000,000. Actual capital expenditures were $17,303,000 in Canada and $29,894,000 in Indonesia, for a total of $47,197,000.

The capital expenditure budget for 2002 is $50,000,000; however, this amount is not fixed and may be amended depending on opportunities and capital availability. The Corporation has no significant fixed capital commitments.

Finding and development costs for 2001 were $13.22 per boe for proved reserves and $20.97 per boe for proved plus 1/2 probable reserves. On a four-year average basis, these amounts were $6.66 for proved reserves and $4.89 for proved plus 1/2 probable reserves.

In Canada, 2001 finding and development costs were $7.53 for proved reserves and $12.45 for proved plus 1/2 probable reserves.

In Indonesia, 2001 amounts were $26.11 for proved and $37.90 for proved plus 1/2 probable reserves. Relatively high 2001 Indonesian finding and development costs reflect a 2001 capital program that developed and monetized previously booked proved reserves. Over a four-year period, these costs have averaged $8.16 per boe of proved reserves and $4.61 per boe of proved plus 1/2 probable reserves.

Corporate information provided herein contains forward-looking information. The reader is cautioned that assumptions used in the preparation of such information, which are considered reasonable by the Corporation at the time of preparation, may be proven to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein and the variation may be material. There is no representation by the Corporation that actual results achieved during the forecast period will be the same in whole or in part as those forecast.

MANAGEMENT'S *report*

To the Shareholders of Equatorial Energy Inc.:

The consolidated financial statements of Equatorial Energy Inc. were prepared by and are the responsibility of management. The statements have been prepared in conformity with Canadian generally accepted accounting principles appropriate in the circumstances and include some amounts that are based on management's best estimates and judgements.

The Corporation maintains systems of internal accounting controls designed to provide reasonable assurance that all transactions are properly recorded in the Corporation's books and records, that policies and procedures are adhered to, and that assets are protected from unauthorized use. The systems of internal accounting controls are complemented by the selection, training and development of professional financial managers.

The consolidated financial statements have been audited by the independent accounting firm, Deloitte & Touche LLP, whose appointment is ratified yearly by the shareholders at the annual shareholders' meeting. The independent accountants conduct a review of internal accounting controls to the extent required by generally accepted auditing standards and perform such tests and related procedures as they deem necessary to arrive at an opinion on the fairness of the financial statements.

The Audit Committee of the Board of Directors periodically meets with the independent accountants and management to satisfy itself that it is properly discharging its responsibilities. The independent accountants have unrestricted access to the Audit Committee, without management present, to discuss the results of their examination and the quality of financial reporting and internal accounting control.

JOHN R. ROONEY
President and
Chief Executive Officer

MICHAEL A. WILHELM
Vice President Finance and
Chief Financial Officer

MARCH 26, 2002

AUDITORS' *report*

To the Shareholders of Equatorial Energy Inc.:

We have audited the consolidated balance sheets of Equatorial Energy Inc. as at December 31, 2001 and 2000 and the consolidated statements of operations and retained earnings and of cash flows for the years then ended. These consolidated financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2001 and 2000 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP
Chartered Accountants
Calgary, Alberta

MARCH 01, 2002

consolidated
BALANCE SHEETS

December 31 *(000s)*	2001	2000
Assets		
Current		
Cash	**$ 7,702**	$ 4,485
Accounts receivable	**20,064**	28,469
	27,766	32,954
Petroleum and Natural Gas Interests (Note 3)	**118,011**	129,896
	$ 145,777	$ 162,850
Liabilities		
Current		
Accounts payable and accrued liabilities	**$ 23,087**	$ 24,981
Current portion of long-term debt *(Note 4)*	**42**	17,990
	23,129	42,971
Long-term Debt (Note 4)	**51,737**	47,284
Future Income Taxes (Note 9)	**22,577**	27,959
Site Restoration and Abandonment	**2,129**	2,119
	99,572	120,333
Shareholders' Equity		
Share capital *(Note 5)*		
Common shares	**42,816**	18,544
Series 1 convertible preferred shares	**–**	12,000
Retained earnings	**3,389**	11,973
	46,205	42,517
Commitments (Note 11)		
	$ 145,777	$ 162,850

See accompanying notes.

ON BEHALF OF THE BOARD

Director

Director

consolidated statements of

OPERATIONS AND RETAINED EARNINGS

Years ended December 31 *(000s)*	2001	2000
Revenue		
Gross oil and natural gas revenue	**$ 136,162**	$ 128,582
Royalties and government share	**(46,962)**	(40,847)
	89,200	87,735
Expenses		
Operating	**31,699**	25,310
Depletion, depreciation and amortization	**28,802**	21,638
Write-down of petroleum and natural gas interests	**30,135**	–
Interest – long-term debt	**4,241**	6,619
Administrative	**7,523**	5,716
Foreign exchange and other	**1,057**	(489)
	103,457	58,794
(Loss) Income Before Income Taxes	**(14,257)**	28,941
(Recovery of) Provision for Income Taxes *(Note 9)*	**(5,865)**	14,848
Net (Loss) Income for the Year	**(8,392)**	14,093
Retained Earnings, Beginning of Year	**11,973**	1,796)
Adjustment for change to future tax accounting *(Note 9)*	**–**	(3,136)
Dividends paid on preferred shares *(Note 5)*	**(192)**	(780)
Retained Earnings, End of Year	**$ 3,389**	$ 11,973
Net (loss) earnings per common share – basic *(Note 7)*	**$ (0.34)**	$ 0.70
Net (loss) earnings per common share – diluted *(Note 7)*	**$ (0.34)**	$ 0.56

consolidated statements of
CASH FLOWS

Years ended December 31 *(000s)*	2001	2000
Cash Flows from the following:		
Operating Activities		
Net (loss) income for the year	**$ (8,392)**	$ 14,093
Items not affecting cash:		
Depletion, depreciation and amortization	**28,959**	21,835
Write-down of petroleum and natural gas interests	**30,135**	–
Future income taxes	**(8,121)**	14,418
Unrealized foreign exchange losses	**1,268**	132
Cash flow from operations	**43,849**	50,478
Changes in non-cash working capital *(Note 10)*	**6,512**	(8,068)
	50,361	42,410
Financing Activities		
Repayment of long-term debt	**(15,587)**	(8,848)
Dividends paid on preferred shares	**(192)**	(780)
Issue of common shares (net of issue expenses)	**13,761**	287
Issue of US dollar note	**2,071**	–
	53	(9,341)
Investing Activities		
Petroleum and natural gas expenditures	**(50,849)**	(41,496)
Site restoration and abandonment	**(812)**	(1,253)
Proceeds on sale of petroleum and natural gas interests	**4,464**	5,522
	(47,197)	(37,227)
Foreign exchange loss on long-term debt – deferred	**–**	487
Net Increase (Decrease) in Cash	**3,217**	(3,671)
Cash, Beginning of Year	**4,485**	8,156
Cash, End of Year	**$ 7,702**	$ 4,485
Cash flow from operations per common share – basic *(Note 7)*	**$ 1.74**	$ 2.62
Cash flow from operations per common share – diluted *(Note 7)*	**$ 1.53**	$ 2.02

Years Ended December 31, 2001 and 2000
(Tabular amounts are in thousands of dollars except for share and per share amounts)

1. Nature of Business

Equatorial Energy Inc. and its subsidiaries (the "Corporation"), is in the business of exploration, development and production of petroleum and natural gas interests.

2. Significant Accounting Policies

(a) Basis of presentation

The consolidated financial statements are presented in accordance with Canadian generally accepted accounting principles and are expressed in Canadian dollars.

(b) Basis of consolidation

The consolidated financial statements include the accounts of the Corporation and its wholly-owned subsidiaries, Equatorial Energy (International) Inc. ("EQII"), Equatorial Energy Trading Corp. ("EETC"), Pilona Petro Tanjung Lontar Ltd. ("Pilona"), Equatorial Energy (Indonesia) Inc. ("EEII") and Auckland Investments Pty. Ltd. The consolidated financial statements also include the accounts of its 80% owned subsidiary, Perkasa Equatorial Sembakung Ltd. ("Perkasa"). All intercompany transactions and accounts have been eliminated.

(c) Cash

Cash includes short-term investments with a maturity of ninety days or less at the time of issue.

(d) Petroleum and natural gas interests

The Corporation follows the full cost method of accounting for petroleum and natural gas interests whereby all costs of exploring and developing petroleum and natural gas reserves, net of government grants, are capitalized by individual country cost centre. Such costs include land acquisition costs, geological and geophysical expenses, costs of drilling both productive and non-productive wells, tangible equipment and administrative costs directly related to acquisition, exploration and development activities.

For each cost centre, the total carrying value of the Corporation's petroleum and natural gas interests, less accumulated depletion and depreciation, is limited to the estimated future net revenue from production of proved reserves, based on unescalated prices and costs plus the lower of cost and net realizable value of unproved properties, less estimated future development costs, site restoration and abandonment costs, administrative expenses, financing costs and income taxes. The carrying value of unproved properties is reviewed periodically to ascertain whether impairment has occurred. If impairment occurs, the costs will be written down to their net realizable value.

In Indonesia, the Corporation has no ownership interest in the producing assets nor in the oil and gas reserves, but rather has the right to operate the assets and receive production and/or revenues from the sale of oil and gas in accordance with the petroleum sharing agreements. Proved reserves have therefore been determined on a net entitlement basis, which takes into account projections of the government's share of production calculated with certain price and expenditure assumptions.

For each cost centre, the costs associated with proved reserves are depleted or depreciated using the unit-of-production method based on an independent engineering estimate of proved reserves, before royalties and government share, with natural gas converted to its energy equivalent at a ratio of six thousand cubic feet of natural gas to one barrel of oil.

The Corporation provides for future estimated site restoration costs using the unit-of-production method based on costs and regulations in effect at the end of the year.

Office equipment is amortized on a straight-line basis over five years.

(e) Government share

All operations conducted jointly with the Indonesian national oil company ("PERTAMINA") are reflected in these consolidated financial statements. All PERTAMINA interests, other than income taxes, are considered to be government share. Government share on production from Indonesian properties represents the entitlement of PERTAMINA to a portion of the production of crude oil, liquids and natural gas and are recorded using rates in effect under the terms of contracts at the time of production.

Under the terms of each contract, the Corporation is entitled to use gross proceeds of production to recover substantially all of the non-capital costs incurred during each year as well as current year depreciation for capital costs and any costs unrecovered from prior years. Such gross proceeds of production are included in revenue before government share.

The maximum cost recovery in any year is 80% of gross revenue for the first two years of production, and depending on the production sharing contract, 65% to 80% thereafter. PERTAMINA and the Corporation are entitled to share the remaining oil profits based upon the terms in each contract. The Corporation's share of oil production is the rate that will provide an after-tax profit share of 15%.

(f) Foreign currency translation

Transactions of the Corporation that are denominated in foreign currencies are recorded in Canadian dollars at exchange rates in effect at the related transaction dates. Monetary assets and liabilities denominated in foreign currencies are adjusted to reflect exchange rates at the consolidated balance sheet date. Non-monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate in effect when the assets were acquired or the liabilities assumed. Exchange gains and losses arising on the translation of monetary assets and liabilities are included in the determination of income for the year.

(g) Stock-based compensation plans

The Corporation has stock-based compensation plans as described in Note 6. No compensation expense is recognized when stock options are issued.

Consideration paid on exercise of stock options is credited to share capital. The Corporation may grant share appreciation rights as described in Note 6. The cost of such rights is accrued over the period it relates to and accounted for as an expense.

(h) Flow-through Shares

Under the terms of Canadian flow-through share legislation, the tax attributes of qualifying expenditures are renounced to subscribers. To recognize the foregone tax benefits, share capital is reduced and a future income tax liability is recorded as the related expenditures are made.

(i) Joint Venture Activities

The Corporation's exploration and development activities are conducted jointly with others, and accordingly, the accounts reflect only the Corporation's proportionate interest in such activities.

(j) Income Taxes

The Corporation accounts for income taxes on the liability method. Under this method, future income tax assets and liabilities are measured based upon temporary differences between the carrying values of assets and liabilities and their tax basis. Income tax expense or recovery is computed based on the change during the year in the future tax assets and liabilities. Effects of changes in tax laws and tax rates are recognized when substantially enacted.

(k) Earnings Per Share

The Corporation retroactively adopted, with all prior periods restated, the new accounting recommendation of the Canadian Institute of Chartered Accountants "Earnings Per Share". As a result of this change, the treasury stock method is used instead of the imputed interest method to determine the dilutive effect of stock options and warrants. Had the treasury stock method not been adopted, diluted net earnings per common share would have been unchanged at $(0.34) (2000 – $0.51) and diluted cash from operations per common share would have been $1.40 (2000 – $1.79).

3. Petroleum and Natural Gas Interests

2001	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas interests	**$ 227,106**	**$ (109,626)**	**$ 117,480**
Other assets	**1,037**	**(506)**	**531**
	$ 228,143	**$ (110,132)**	**$ 118,011**
2000			
Petroleum and natural gas interests	$ 181,194	$ (51,612)	$ 129,582
Other assets	619	(305)	314
	$ 181,813	$ (51,917)	$ 129,896

As at December 31, 2001, unproved Canadian properties with capitalized costs of $13,000,000 (2000 – $17,500,000) were not subject to depletion.

Unproved Indonesian properties of $nil in 2001 (2000 – $20,817,016) were also not subject to depletion.

During the year ended December 31, 2001, the Corporation capitalized overhead charges related to petroleum and natural gas exploration and development activities of $2,476,268 (2000 – $2,139,726).

4. Long-term Debt

	2001	2000
Revolving bank credit facility with interest accruing monthly at the Corporation's choice of any of the following rates: Canadian prime plus 1.25%, U.S. Base rate plus 1.25%, LIBOR rate plus 2.25% or Bankers' Acceptance rate plus 2.25% quarterly. There are no principal repayments required until maturity in 2004. The loan is secured by a fixed and floating charge debenture, over its Canadian oil and gas properties and by a general security agreement. The Corporation's banker has been granted priority over all assets other than the Corporation's existing rights and interests in Indonesia.	**$ 40,000**	$ 37,500
Promissory notes of US$11,682,421, repaid prior to maturity on March 28, 2001.	**–**	17,518
Promissory note of US$1,300,000 due on January 1, 2004 which accrues simple interest at 4% per annum.	**2,071**	–
Promissory note due on the later of February 25, 2005 and one day following the repayment by the Corporation of all amounts owing under its existing bank agreements. Interest accrues and is paid quarterly at 7.2% per annum. The Corporation may pre-pay any or all of the outstanding principal and interest, but must, in certain circumstances, pay a pre-payment premium of 6.67% in 2002 which declines by 2.22% per calendar year until it becomes 1.11% in 2005 and expires thereafter. If certain defaults occur, the note and any accrued interest is convertible, at the option of the vendor, into common shares at a price of $2.2712 per share.	**9,666**	9,666
US$630,000 non-interest bearing promissory note.	**42**	590
	$ 51,779	$ 65,274
Less: current portion	**(42)**	(17,990)
	$ 51,737	$ 47,284

At December 31, 2001, $340,000 (net of accumulated amortization of $449,000) of financing costs have been deferred and will be amortized over the remaining terms of the related debt.

5. Share Capital

(a) Authorized

Unlimited number of common shares
Unlimited number of preferred shares

(b) Issued

	Number of Shares	Amount
Common Shares		
Balance at December 31, 1999	18,701,288	**$ 16,513**
Adjustment for change to future tax accounting	–	**3,468**
Issued for cash		
Exercise of common share purchase options	126,125	**177**
Exercise of common share purchase warrants	92,500	**203**
Issued on conversion of debentures	245,000	**350**
Tax benefits renounced to flow-through investors	–	**(2,144)**
Common share issue expenses (net of tax)	–	**(23)**
Balance at December 31, 2000	19,164,913	**18,544**
Issued for cash		
On exercise of Special Warrants	2,000,000	**5,200**
On exercise of flow-through Special Warrants	1,350,000	**4,388**
Flow-through common shares	1,500,000	**3,000**
Exercise of common share purchase warrants	626,250	**1,628**
Exercise of common share purchase options	301,250	**437**
Issued on conversion of Series 1 Preferred Shares	5,283,550	**12,000**
Tax benefits renounced to flow-through investors	–	**(1,870)**
Common share issue expenses (net of tax)	–	**(511)**
Balance at December 31, 2001	30,225,963	**$ 42,816**

(c) Issue of Special Warrants

During 2001, the Corporation completed a private placement of 3,350,000 special warrants (the "Special Warrants") for gross proceeds of $9,587,500. Each Special Warrant was exercisable, at no additional cost, into one common share. All of the Special Warrants were exercised on April 27, 2001.

(d) Flow-through Shares

At December 31, 2001, a total of $7,387,500 of Canadian Exploration Expenses were renounced to shareholders. Related expenditures of $4,387,500 were incurred during 2001, and $3,000,000 is to be incurred in 2002.

(e) Series 1 Convertible Preferred Shares

The Series 1 Convertible Preferred shares paid dividends at 6.5% per year and were converted to common shares of the Corporation on May 29, 2001.

(f) Warrants

The following warrants for purchase of common shares are outstanding at December 31, 2001:

Date Granted	Number of Common Shares	Excercise Price	Expiry Date
February 26, 1999	1,766,250	$ 2.60	February 25, 2002

No value has been ascribed to any of the warrants for accounting purposes. On February 25, 2002 the warrants expired unexercised.

6. Stock Option and Share Appreciation Rights Plans

(a) Stock Option Plan

Under the Corporation's stock option plan, the Corporation may grant options to its directors, officers, employees and service providers to purchase common shares at a fixed price not less than the fair market value of the stock on the day preceding the grant date. The Corporation has reserved 1,875,000 common shares for grants of options. The maximum term of the options is 10 years. The options are exercisable as to 25% per year beginning on the date of grant.

	Number of Options	Weighted Average Exercise Price
Options		
Outstanding at December 31, 1999	1,712,500	$ 1.62
Granted	417,500	1.99
Exercised	(126,125)	1.40
Cancelled	(238,375)	1.41
Outstanding at December 31, 2000	1,765,500	1.75
Granted	30,000	2.40
Exercised	(270,000)	1.40
Cancelled	(50,000)	7.80
Cancelled	(18,750)	1.40
Exercised	(25,000)	1.76
Exercised	(6,250)	2.40
Outstanding at December 31, 2001	1,425,500	1.62
Exercisable at December 31, 2001	950,375	1.58

(a) Stock Option Plan (Continued)

The following table summarizes information about the Corporation's stock options outstanding at December 31, 2001.

Exercise Price $	Options Outstanding at 12/31/01	Remaining Contractual Life (Years)	Options Exercisable at 12/31/01
$ 1.40	$ 954,250	2.50	$ 715,688
1.45	45,000	3.00	22,500
1.85	10,000	3.00	5,000
1.76	134,500	3.30	67,250
2.05	160,000	3.50	80,000
2.30	78,000	3.70	39,000
2.35	10,000	3.50	5,000
2.40	23,750	4.00	5,937
6.20	10,000	0.70	10,000
$ 1.40 – 6.20	$ 1,425,500	2.73	$ 950,375

(b) Share Appreciation Rights Plan

Under the Corporation's share appreciation rights plan, the Corporation may grant share appreciation rights to its directors, officers, employees or providers of services. Each right entitles the participant to receive from the Corporation an amount equal to the positive difference, if any, obtained by subtracting the assigned amount from the simple average of the closing trading price of the common shares on the TSE for up to 20 trading days immediately preceding the date of exercise.

The following table summarizes information about the Corporation's share appreciation rights plan at December 31, 2001.

Base Value $	Number	Remaining Contractual Life (Years)	Terms
1.40 – 1.45	407,500	5.76	25% exercisable immediately with an additional 25% on the next 3 anniversary dates
2.30	87,500	6.61	25% exercisable on each of the first 4 anniversary dates
2.40 – 2.90	595,000	7.21	25% exercisable immediately with an additional 25% on the next 3 anniversary dates
	1,090,000	6.62	

In 2001, $464,066 (2000 – $138,904) has been recorded as expense.

7. Per Common Share Amounts

Net earnings and cash flow per common share figures have been calculated using the following numbers of shares:

	2001	2000
Weighted average shares – basic	**25,101,152**	18,978,559
Weighted average shares – diluted	**28,662,008**	24,977,124

Net income and cash flow figures have been reduced by preferred share dividends for the purpose of the basic per common share calculations. In 2001, diluted weighted average shares reflect the dilutive effect of stock options. In 2000, diluted weighted average shares reflect the dilutive effect of preferred shares, stock options, and warrants.

8. Segment Information

The Corporation's activities are conducted in two geographic segments, both relating to the exploration, development, and production of petroleum and natural gas.

The Corporation's two segments operate in Canada and Indonesia. The Corporation's head office is in Canada.

	Canada ($)		Indonesia ($)		Total ($)	
Revenues and Expenses	**2001**	2000	**2001**	2000	**2001**	2000
Gross oil and natural gas revenue	**66,405**	75,753	**86,315**	70,205	**152,720**	145,958
Royalties and government share	**(14,981)**	(15,376)	**(31,981)**	(25,471)	**(46,962)**	(40,847)
	51,424	60,377	**54,334**	44,734	**105,758**	105,111
Write-down of petroleum and natural gas interests	**–**	–	**30,135**	–	**30,135**	–
Operating	**13,265**	13,142	**18,434**	12,168	**31,699**	25,310
Depletion and depreciation	**10,265**	10,064	**18,537**	11,574	**28,802**	21,638
Segment operating income (loss)	**27,894**	37,171	**(12,772)**	20,992	**15,122**	58,163
Hedging losses	**–**	–	**–**	–	**16,558**	17,376
Interest – long-term debt	**–**	–	**–**	–	**4,241**	6,619
Administrative	**–**	–	**–**	–	**7,523**	5,716
Foreign exchange and other	**–**	–	**–**	–	**1,057**	(489)
(Loss) income before income taxes	**–**	–	**–**	–	**(14,257)**	28,941
Income taxes (recovery)	**–**	–	**–**	–	**(5,865)**	14,848
Net (loss) income	**–**	–	**–**	–	**(8,392)**	14,093

	2001	2000
Additions to petroleum and natural gas interests		
Canada	**$ 17,303**	$ 12,810
Indonesia	**29,894**	24,417
	$ 47,197	$ 37,227
Petroleum and natural gas interests		
Canada	**$ 81,790**	$ 74,898
Indonesia	**36,221**	54,998
	$ 118,011	$129,896

9. Income Taxes

Effective January 1, 2000, the Corporation adopted the liability method of accounting for income taxes. The impact of adopting the liability method was to record a future income tax liability of $3,380,090, decrease retained earnings by $3,136,090, increase share capital by $3,468,550 and increase petroleum and natural gas interests by $3,712,550.

Had the new method not been adopted the net income for 2000 would have been lower by $816,000.

The future income tax provision varies from the amount that would be computed by applying the combined Canadian statutory income tax rates to the loss before taxes as shown below:

	2001	2000
(Loss) income before income taxes	**$ (14,257)**	$ 28,941
Expected income taxes at the Canadian statutory rate of 42.62% (2000 – 44.62%)	**(6,076)**	12,913
Increase (decrease) in income tax expense resulting from:		
Non-deductible Canadian crown charges	**4,987**	6,076
Canadian resource allowance	**(4,615)**	(5,599)
Canadian large corporation tax and provincial capital tax	**705**	429
Income tax impact of deferred charges which have no tax basis	**(2,411)**	–
Non-deductible amounts	**2,323**	679
Effect of higher tax rates in Indonesia	**(778)**	350
	$ (5,865)	$ 14,848

The major components of the future income tax liability are as follows:

	2001	2000
Property and equipment	**$ 23,336**	$ 26,396
Deferred charges	**7,384**	17,091
Future site restoration	**(907)**	(945)
Canadian non capital losses and other deductions carried forward	**(6,461)**	(13,794)
Share issue costs	**(775)**	(789)
	$ 22,577	$ 27,959

The Corporation's non-capital losses for Canadian income tax purposes of approximately $12,700,000 are available to be carried forward to offset income in future years and expire in 2007.

10. Statements of Cash Flows

	2001	2000
Changes in non-cash working capital:		
Accounts receivable	**$ 8,405**	$ (15,202)
Accounts payable and accrued liabilities	**(1,893)**	7,134
	$ 6,512	$ (8,068)
Cash interest paid during the year	**$ 4,084**	$ 6,422
Cash taxes paid during the year	**$ 1,053**	$ 429

11. Hedging and Financial Instruments

The Corporation's financial instruments recognized on the consolidated balance sheet include cash, accounts receivable, accounts payable and accrued liabilities and long-term debt. The fair values of financial instruments other than long-term debt approximate their carrying amounts due to the short-term nature of these instruments.

At December 31, 2001, the Corporation had $40,000,000 of variable rate bank loans. There were no instruments in place at December 31, 2001 or 2000 to fix the interest rate on this variable rate debt. At December 31, 2001 and 2000, the reported value of the long-term debt approximates fair value.

The Company has debt denominated in both US dollars and Canadian dollars. In addition, the Company's revenue stream is based on US dollar based commodities, although the Company reports in Canadian dollars. The Company has no instruments in place at December 31, 2001 to fix the exchange rates on these items.

The nature of the Corporation's operations results in exposure to fluctuations in commodity prices. The Corporation enters into derivative contracts connected to its crude oil and natural gas production to manage its exposure to commodity price risks.

The Corporation is exposed to credit-related losses in the event of non-performance by counter-parties. Hedge contracts have been entered into with the bank that has provided the revolving bank credit facility. The Company remains exposed to credit-related losses with all other counter-parties.

The Corporation has entered into natural gas and crude oil contracts for 2002 and future years as follows:

Delivery period	Quantity per day	Price (US$)	Nature of Contract
April 1, 2001 to June 30, 2003	Natural Gas – 13,000 MMBTU	$ 2.40	Sold a call
May 1, 2001 to April 30, 2004	Crude Oil – 500 BBLS	$ 18.65	Sold a call

12. Comparative Figures

Certain of the comparative figures have been reclassified to conform to the presentation adopted for the current year.

CORPORATE *information*

Board of Directors

ROBERT R. ROONEY [2,3] – CHAIRMAN
Partner, Bennett Jones LLP
Barristers and Solicitors

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President
Equatorial Energy (International) Inc.

GEORGE W. WATSON [1,3]
Executive Chairman
VerticalBuilder.com Inc.

PETER G. MEREDITH [1,2]
Chief Financial Officer
Ivanhoe Capital Corporation

DOUGLAS G. MANNER [2,3]
Chairman and Chief Executive Officer
Mission Resources Corporation

FREDRICK F. DALLEY [1]
Managing Director, Portfolio Management
Arrow Hedge Partners Inc.

Officers

JOHN R. ROONEY
President and
Chief Executive Officer

MIKE MACHALSKI
Chief Operating Officer, Canada

MIKE WILHELM
Vice President, Finance and Chief
Financial Officer

Notes:
1. Audit Committee
2. Compensation Committee
3. Reserves Committee

Solicitors

Bennett Jones LLP
Calgary, Alberta

Bankers

J.P. Morgan Bank Canada
Bank One Canada

Auditors

Deloitte & Touche LLP
Calgary, Alberta

Independent Reservoir Consultants

Gilbert Lausten Jung Associates Ltd.
Calgary, Alberta

Transfer Agent

Valiant Trust Company
Calgary, Alberta

Stock Exchange Listing

Listed on the Toronto Stock Exchange
Trading symbol: OZ

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The Annual Meeting will be held at
3:00 p.m. on May 30, 2002 at
The Metropolitan Centre in the The Plaza Room,
333 – 4th Avenue SW, Calgary, Alberta

STAFF *listing*

Canada

Colleen Blanchard
Accounts Payable

Joanne Bouwsema
Technical Assistant/ Engineering

Leigh-Anne Bryant
Supervisor Operations Accounting

Fran Derkach
Surface Land Administrator

Tony Edwards
Managing Director – Int'l Exploration

Mass Geremia
Director Investor Relations

Tracy Howard
Executive Administrator

Blaine Kondo
Manager – Operations

Carl Kuntz
Field Superintendent

Mike Machalski
Chief Operating Officer of Canada

Mike Melling
Senior Production Technologist

Holly Millar
Receptionist

Larry Pewar
Manager – Engineering

Mark Powell
VP Exploration

Frank Raffin
Senior Geophysicist

John Rooney
President & C.E.O.

P. David Shenstone
V.P. Land & Business Development

Derek Stonehouse
Senior Exploitation Technologist

Leanne Tangjerd
Accountant

Twila Theede
Technical Assistant/ Exploration

Garry Topolnitsky
Controller

Mike Wilhelm
Vice President Finance & C.F.O.

Tracy Zbrodoff
Mineral Lease Administrator

Indonesia

David N. Matheson
President,
Equatorial Energy (International) Inc.

Pilona Petro Tanjung Lontar Ltd.

K.A. Sjaiful Achmad
President

Moudie Lince
Junior Secretary

Andi Zainal Tjoppo
Junior EDP Operations

Indah Suryanti
Chief Accountant

Koentjoro
Operations Manager

Pahmi Yaya
Senior Accountant

Budi Harman
Senior Geologist

Hadipoerwanto
Operations Support Manager

Muhammad Ismail
Finance Manager

Farita Alimin
Executive Secretary

Yunias Priyoutomo
Drilling & Workover Engineer

Irfan Sutan
Senior Petroelum Engineer

Kemas Sutawijaya
Field Manager

Sugiharto Imam
Field Operations Superintendent

Perkasa Equatorial Sembakung Ltd.

Suryana
General Manager

Warren Johnston
Chief of Drilling & Workover Operations

Roger Lajoie
Financial Analyst

Steve Stachurski
Field Superintendent

Ron Bell
Field Superintendent

P. Simorangkir
Operations Manager

Djamal Afiff
Senior Facilities Engineer

Kosim Kosasih
Senior Reservoir Engineer

Padri Achyarsyah
Treasurer

Suhadji
Senior Drilling Supervisor

Firman Anwar
Logistics & Services Coordinator

Bambang Priambodo
Logistics Contract Coordinator

Deddy Adrian
General Accountant

R. Wulansari
Executive Secretary

Andam Dewi
Administration & Personnel Supervisor

Yusrizal Djamaludin
Cash & Bank Supervisor

Rustam Effendi
Construction Supervisor

Jeane Manopo
Finance Secretary

Soemarmo
Draftsman

M. Ichsan
Civil Engineer

GLOSSARY

API gravity : the American Petroleum Institute's standard for weight per unit of volume of crude oil, given in degrees — higher API gravity crude is more valuable

bcf : billion cubic feet

boe : barrel of oil equivalent

boepd : barrels of oil equivalent per day

bopd : barrels of oil per day

bpd : barrels per day

mcf : thousand cubic feet

mD : millidarcy, a measurement of permeability

mcfpd : thousand cubic feet per day

mmbtu : millions of British thermal units

mmcf : million cubic feet

mmcfpd : million cubic feet per day

mboe : thousands barrels of oil equivalent

mstb : thousands stock tank barrels

DESIGNED BY KARO

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